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ABSTRACT

This paper describes the dynamic and stability properties of wind turbine generators connected to power systems. Both synchronous and induction generators are considered. A comparison is made between wind turbines, steam, and hydro units. The unusual phenomena associated with wind turbines are emphasized. The general control requirements are discussed, as well as various schemes for torsional damping such as speed sensitive stabilizer and blade pitch control. Interaction between adjacent wind turbines in a "wind farm" is also considered.

1. INTRODUCTION

The purpose of this paper is to provide an overview of the general dynamic characteristics of wind turbine generators in electric power systems and to discuss the impact of variations in system design and control.

Wind turbine generators possess some special characteristics not shared by steam and hydro units. The obvious one is the variability of the source of energy. Two others, which are less obvious, are the high turbine inertia and the low effective shaft stiffness between turbine and generator. These unusual torsional characteristics have several interesting consequences. First, WIGs have a low frequency (<0.5 Hz) torsional mode, which has to be damped, particularly if the turbine is equipped with blade pitch control. Second, the low stiffness shaft system gives WIGs very good transient stability properties. Third, matching of frequency, phase angle and voltage prior to synchronization is less important. Fourth, the two significant torsional modes are practically decoupled. One is determined by turbine inertia and effective shaft stiffness, the other by generator inertia and electrical stiffness. This has favorable implications for multi-machine installations. Interaction of low frequency torsional modes is very unlikely.

In most of the analysis presented here, attention is focused on single wind turbine generators supplying an infinite bus through an external impedance. This simple configuration facilitates system and control parameter variation over a wide range and provides insights into the general characteristics of wind turbine generators. It is subsequently shown how groups of wind turbine generators interact and how the results of the single machine case can be extended to the multi-machine case.

The material in the paper is organized as follows:

- o The general characteristics of wind turbines as they relate to dynamics and control are described in Section 2. This section analyzes the significance of drive train configurations, discusses modal analyses and evaluates the differences between synchronous and induction generators.
- o In Section 3 the general control requirements as well as actual turbine control systems are outlined and compared with those for steam and hydro turbine generators. Various methods of torsional damping are discussed and compared.
- o Dynamic and transient stability properties are presented in Section 4.

The results reported in this paper are based on analytical work carried out for the Wind Systems Branch of the U.S. Department of Energy, the Wind Energy Projects Office of the National Aeronautics and Space Administration, and Sandia Laboratories.

2. CHARACTERISTICS OF WIND TURBINE GENERATORS

Figure 2.1 is the basic block diagram of a turbine generator system. The peculiarities of a WIG compared to conventional turbine generators lie in the variability of the energy supply, the characteristics of the wind turbine as an energy conversion device, and the geometry of the turbine, shafts, gears, and generator which comprise the torsional system.

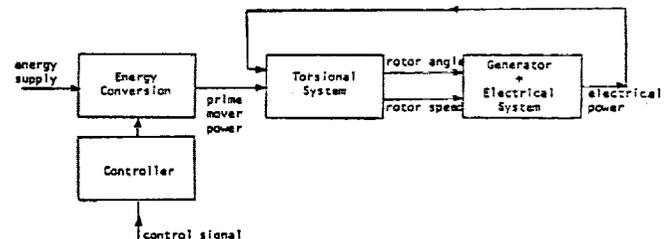


Figure 2.1 Turbine Generator System

At the present time, the horizontal axis propeller turbine and the vertical axis Darrieus turbine are the most likely choices for commercial electric power generation. (Figure 2.2). Both are low-speed machines with large diameter, high inertia rotors. Typical rotor speeds for large turbines (>1 MW) are 20-50 rpm. Typical per unit rotor inertias referred to turbine rating are 5-15 seconds. The large diameter, high inertia rotors are a result of the relatively low energy density of wind. Average wind energy densities in favorable locations are less than one thousand watts per square meter of area swept by the rotor. Both types of turbines achieve their best extraction efficiencies at

tip speed/wind speed ratios of 6-8. In that range, the efficiency is approximately 0.4. The theoretical maximum efficiency is 0.59. The large rotor diameter required for energy capture and the tip speed/wind speed ratio required for good efficiency determine rotor speed.

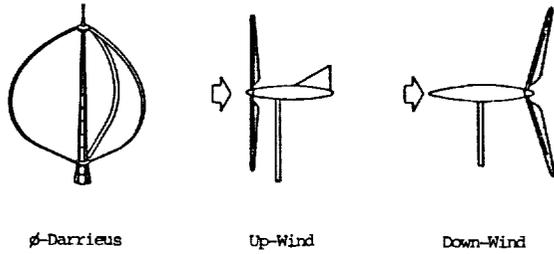


Figure 2.2 Wind Turbine Designs

Most large wind turbines operate at constant speed, driving standard three-phase ac generators. Synchronous as well as induction generators are used. Generators of suitable dimensions and reasonable cost are four- or six-pole machines with synchronous speeds of 1800 or 1200 rpm. The large difference between turbine and generator speeds makes gearboxes essential elements of wind turbine generator drive trains. The consequence of the gearbox in terms of drive train dynamics is low mechanical stiffness between generator and turbine when viewed from the generator. Figure 2.3 is a comparison of typical inertia-stiffness relationships in steam, hydro, diesel, and wind turbine generators. The unusual characteristics of WTG drive trains are evident from this comparison. The WTG is the only turbine generator in utility networks with a mechanical stiffness lower than the electrical stiffness (synchronizing torque coefficient) [2].

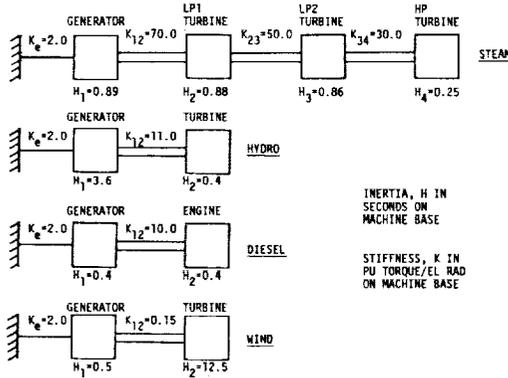
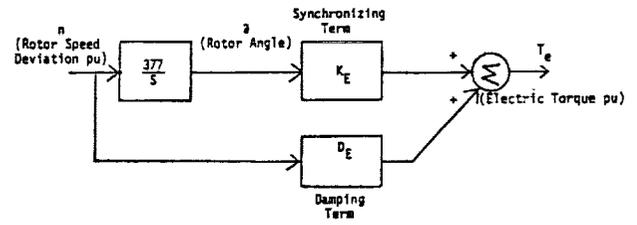


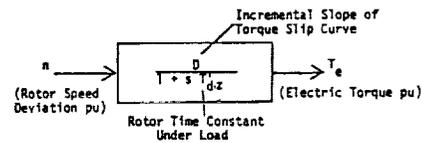
Figure 2.3 Comparison of Drive Trains of Typical Turbine Generators

For analysis of the mode shapes the electrical tie of the synchronous machine can be represented by a torsional spring (Figure 2.4.a). A low slip induction generator may be represented by the block diagram shown in Figure 2.4.b. This simplified representation includes the rotor dynamics of a single rotor circuit and embraces an algebraic solution of the network. T'_{dz} is typically 1 second and D lies in the range 50 to 500 p.u. It is evident that over the frequency range of interest the dynamics of both machines are similar, and that the induction generator can also be represented by

an equivalent "synchronizing coefficient." Irrespective, therefore, of the type of generator, the torsional coupling between generator and synchronous frame has been represented as a torsional spring. Figure 2.5 shows mode shapes and modal frequencies of the 2.5 MW MOD-2 horizontal axis WTG designed by Boeing. Figure 2.6 shows the mode shapes and modal frequencies of the 2.0 MW MOD-1 horizontal axis WTG designed by General Electric, and Figure 2.7 depicts the same information for the 60 kW, 17 meter vertical axis Darrieus WTG designed by Sandia Laboratories. Even though the three machines are very different in size and design, the mode shapes are quite similar. The electrical stiffness selected for this analysis is 2.0 pu. This is a typical value for machine, network and loading in a WTG system. The lowest torsional mode in Figures 2.5, 2.6 and 2.7 represents oscillation of the turbine rotor through the shaft against generator and infinite bus equivalent of the electrical system. Since electrical stiffness is much higher than apparent mechanical stiffness, the relative torsional amplitude of the generator rotor is very small. It is evident that the frequency of this mode is almost entirely determined by turbine inertia and shaft stiffness, not by electrical parameters.



(a) Synchronous Generator



(b) Induction Generator

Figure 2.4 Simplified Block Diagrams for Synchronous and Induction Generators

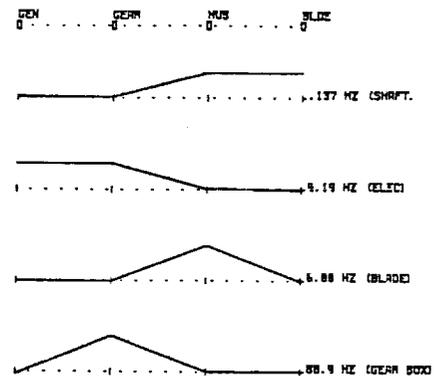


Figure 2.5 Mode Shapes of MOD-2 WTG

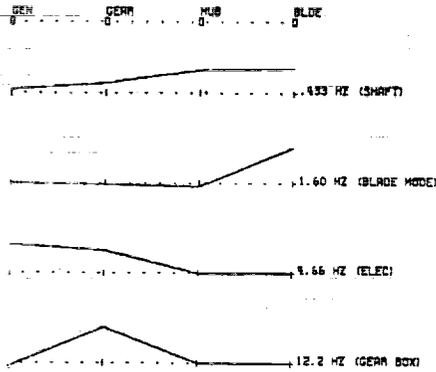


Figure 2.6 Mode Shapes of MOD-1 WIG

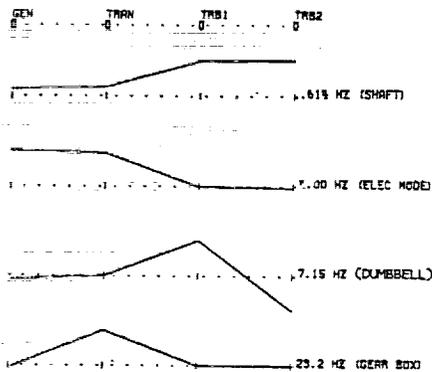


Figure 2.7 Mode Shapes of Sandia 17 M WIG

The second torsional mode in Figures 2.5 and 2.7 and the third mode in Figure 2.6 represent oscillation of the generator rotor through the electrical stiffness against the equivalent infinite bus. Turbine rotor participation in this "electrical" mode is insignificant. The frequency of this mode is primarily determined by generator inertia and synchronizing coefficient, which depends on loading, generator, and network characteristics. The frequency is essentially independent of turbine parameters.

For an analysis of the dynamics of WIGs connected to electric power systems, torsional modes other than the two discussed here can generally be neglected. They are either well damped or their frequencies are above the range of interest.

Figures 2.5, 2.6, and 2.7 further reveal that the first torsional mode is most easily stimulated by transients acting on the turbine, while the "electrical" mode responds primarily to stimulation acting through the generator.

The frequencies and mode shapes in Figures 2.5 and 2.6 describe the system without control. Blade pitch control with proportional action on electric power increases the frequency of the first torsional mode.

These mode shapes may be contrasted with those of a typical steam generator, where all the inertias move with almost equal amplitude at the low frequency system

mode. The normal approximation for stability work is to combine all inertias into a single inertia connected to the electrical system through the equivalent electrical stiffness. In a WIG, by contrast, the generator inertia can be considered decoupled from the hub and blade inertias in the electrical mode. The effective stiffness between generator and turbine is very low. Relatively high "electrical" mode frequencies are then possible due to the nearly unconstrained motion of the generator inertia against the electrical system.

3. WIND TURBINE CONTROL

The overall linearized block diagram of a WIG, including pitch control, torsional system, generator, electrical system, and provisions for damping the first torsional mode, is shown in Figure 3.1.

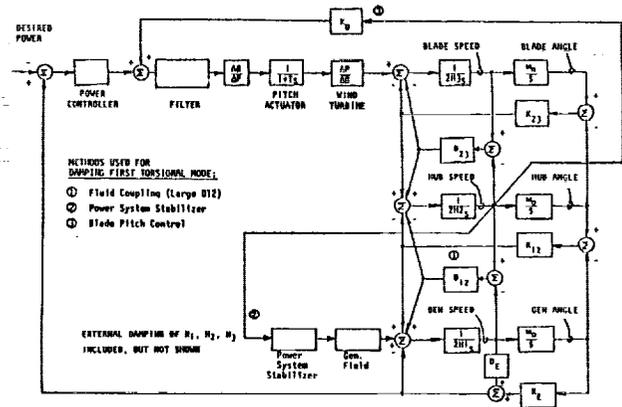


Figure 3.1 Linearized Model of WIG

In addition to drive train configuration, turbine blade pitch control has a significant impact on dynamic behavior. This type of control only exists in horizontal axis machines. Variable pitch turbines operate efficiently over a wider range of wind speeds than fixed pitch machines. Cost and complexity are higher. It is generally found that a sufficiently responsive pitch control system has a bandwidth that includes the frequency of the first torsional mode, i.e., this mode is stimulated by control action. Therefore, additional damping for the lightly damped first torsional mode is required. Three different methods of damping have been used in variable pitch turbines developed within the U.S. Federal Wind Energy Program:

- o Generator damping either through the use of a power system stabilizer or by the inherent damping of an induction generator.
- o Addition of a damping signal to the pitch controller.
- o Fluid coupling between turbine and generator.

In the MOD-1 WIG, damping is achieved by a speed sensitive power system stabilizer. Turbine hub speed is used as the input. It can be seen qualitatively from the mode shapes of Figure 2.6 that the stabilizer operates on a relatively small component of generator motion in the first torsional mode, and can be expected to require large torques to influence shaft motion at this frequency. Loci of eigenvalues as function of stabilizer gain confirm the relative ineffectiveness of this means of providing damping to the first torsional mode.

A stabilizer can have a destabilizing effect on the "electrical" mode. This happens when there is a phase reversal between generator and hub displacements in the "electrical" mode.

In the MOD-2 WIG, a damping signal in phase with hub speed is summed with the output of the pitch controller. The time response plot of Figure 3.2 shows the effectiveness of this damping component. Figure 3.2 depicts the response of electrical power to a step change in wind power. The difference between the two traces marked "base design" and "no hub damping" is caused by the damping component. The third trace in Figure 3.2 marked "no control" shows the response without pitch control. It should be noted that in this case the addition of pitch control increases the frequency of the first torsional mode. The proportional component of power control introduces stiffness between turbine and generator inertias. Figure 3.3 shows the eigenvalues as wind speed changes. The variation in wind speed changes the incremental wind power/pitch angle relationship and thereby affects the transfer function of the control loop. It can be seen that the system is adequately damped over the whole wind speed range.

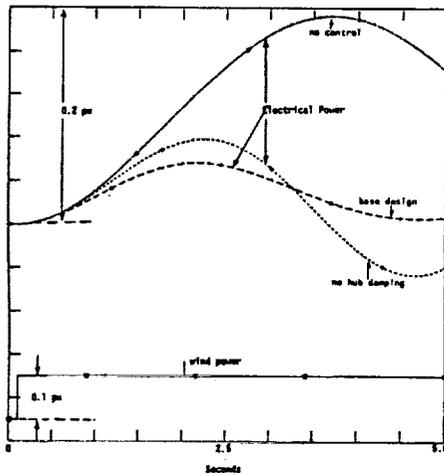


Figure 3.2 Effect of Damping with Pitch Control

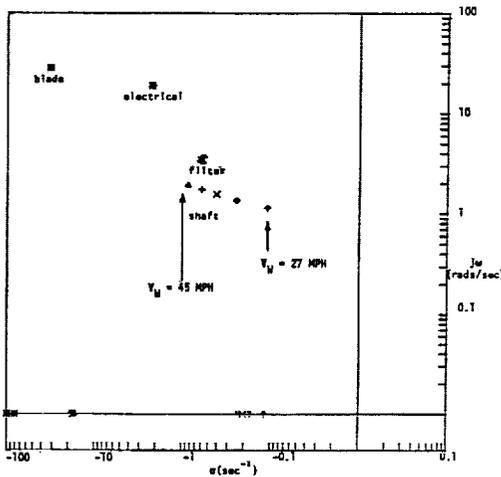


Figure 3.3 Effect of Varying Wind Speeds-MOD-2 WIG

Reference [1] describes a WIG control system which also uses pitch variations for introducing damping. A compensating network is included in the hub speed loop to offset servo lag.

Figure 3.4 shows that damping of the first torsional mode can also be introduced by a high slip induction generator. This would not be an effective mechanism in a WIG such as the MOD-2 because generator motion in the first torsional mode is extremely small (Figure 2.5). In a MOD-1 WIG, generator motion in the first torsional mode is larger (Figure 2.6). Damping with a high slip induction generator would be more effective, however, losses would be high.

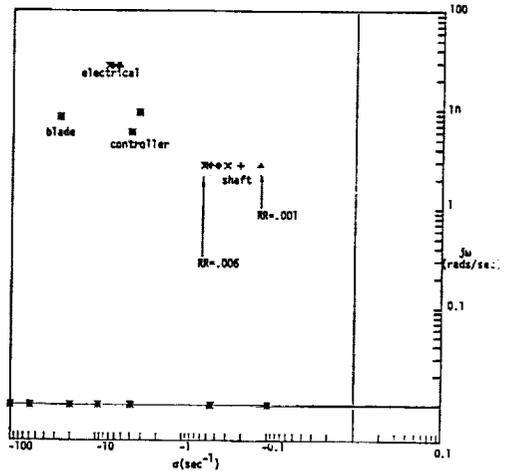


Figure 3.4 Effect of Varying Induction Generator Rotor Resistance, MOD-1 Drive Train

In the MOD-0 and MOD-0A, a fluid coupling is used. This is a very effective damping device but it introduces losses.

In addition to finding a suitable balance between control response and damping of the first torsional mode, the controlled variable has to be selected. For primary control, this can either be speed or power. Current WIGs use power. This selection has been based on the assumption that electric power systems are infinitely large compared to wind turbines and that constant power generated by WIGs can always be absorbed. There are two disadvantages:

- o WIGs using power control do not participate in load sharing.
- o The power controller cannot differentiate between changes it should respond to, i.e., changes caused by the turbine, and those it should not respond to, i.e., changes originating in the electrical system.

Use of turbine speed as the controlled variable would have three advantages:

- o Pitch control would not respond to system disturbances unless they affect turbine speed.
- o Speed is the controlled variable for turbine controllers of conventional turbine generators. Turbine speed controllers have proportional characteristics so that the speed droops slightly with load. This provides

load sharing capability. WTGs will not always be applied to systems infinitely large compared to their rating. They must be able to participate in transient load sharing.

- o Speed control is dynamically superior to power control. Turbine torque excursions are integrated once and become speed excursions. They are integrated again before showing up as power angle and electric power excursions.

A combination of primary speed control and slower resetting type power control is traditional in power systems.

4. DYNAMICS AND STABILITY

The following issues were addressed:

- o Dynamic stability of a single wind turbine generator connected to a strong system.
- o Dynamic stability of a group of wind turbines synchronized to a common bus and connected to a strong system.
- o Transient stability following disturbances at the mechanical end (wind speed changes) and at the electrical end (faults) of the WTG drive train.
- o Shaft torque levels during disturbances.
- o Synchronization.

Dynamic Stability of Single Wind Turbine

The dynamic stability of a single wind turbine generator was investigated by obtaining the eigenvalues of wind turbine systems for variations in the electrical system. In the case of a synchronous generator KE (the synchronizing coefficient) was modified to reflect these variations. Results are shown in Figure 4.1. In the case of an induction generator XE (the electrical system reactance) was modified to show the effect of variations in transmission strength. Results are similar to Figure 4.1. It is evident that only the electrical system mode is affected by these changes. It was noted earlier that this mode is nearly independent of the mechanical properties of the turbine.

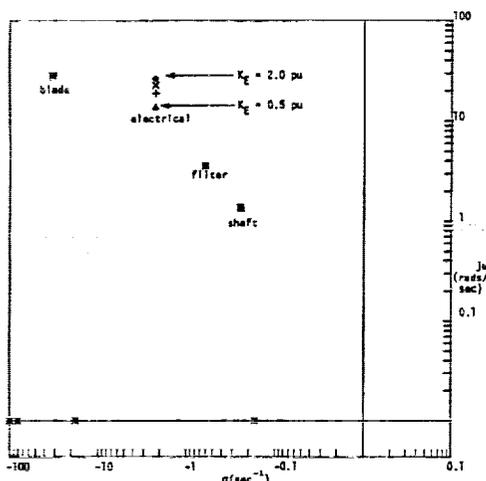


Figure 4.1 Effect of Varying Electrical Stiffness

Dynamic Stability of Groups of Wind Turbines

Most of the analyses presented so far have been based on systems with single WTGs connected to an infinite bus. In view of the variability of wind energy, there has been concern about interactions between adjacent wind turbine generators through the electrical network.

In the case of two identical wind turbines synchronized and connected to a stiff system, the dynamics comprise two sets of modes:

- o Wind turbine generators move coherently with each other. These "in phase" modes are stimulated by wind speed disturbances of the same magnitude and sign applied to each machine. Electrical disturbances on the common transmission system also excite these modes.
- o Wind turbine generators move against each other with equal and opposite magnitudes. It is not possible to excite these "anti-phase" modes by disturbances on the common electrical transmission. The bus at which the machines are synchronized represents a node for all anti-phase modes.

The dynamics of such a system can be analyzed in terms of two equivalents:

- o A lumped equivalent machine swinging against the receiving end infinite bus.
- o A single machine swinging against the bus at which the machines are synchronized.

It was concluded earlier that the first torsional mode is practically unaffected by the transmission system strength. Consequently, the natural frequency and damping of the first torsional mode is approximately the same for the single system and inter-system modes. It follows that a WTG designed for the first torsional mode in a single machine application will also satisfy damping requirements for intermachine first torsional modes in multi-machine applications.

The intermachine electrical modes are not particularly significant. There are three reasons:

- o They generally have a higher frequency than the electrical system mode and are better damped.
- o They are not stimulated appreciably by wind speed disturbances. This was shown earlier in the modal analysis of WTG drive trains.
- o They are not stimulated by electrical disturbances common to all adjacent WTGs.

The analysis of interactions between WTGs has been explained in terms of a two machine system synchronized to a common bus. The results can be extended to the general case [3].

Transient Stability

Wind turbine generators are subjected to mechanical disturbances applied at the turbine when there are sudden wind speed changes. They are also subjected to electrical disturbances applied at the generator during electrical transients. While all the possible electrical disturbances are of the same nature for conventional turbine generators as for WTGs, the consequences of particular disturbances are different because the torsional system is different. Mechanical

disturbances of the drive train from the turbine end are a peculiarity of WIGs.

Figure 4.2 shows the response of a MOD-2 WIG to five successive 4 mph step changes in wind speed. Wind speed (mph), mechanical power at the blades (p.u.), electrical power (p.u.), and generator power angle (deg.) are plotted. Pitch control is active to provide power control and damping of the first torsional mode. It is interesting to note that damping of the first torsional mode increases with increasing wind speed. This corroborates the results of the eigenvalue analysis shown in Figure 3.3.

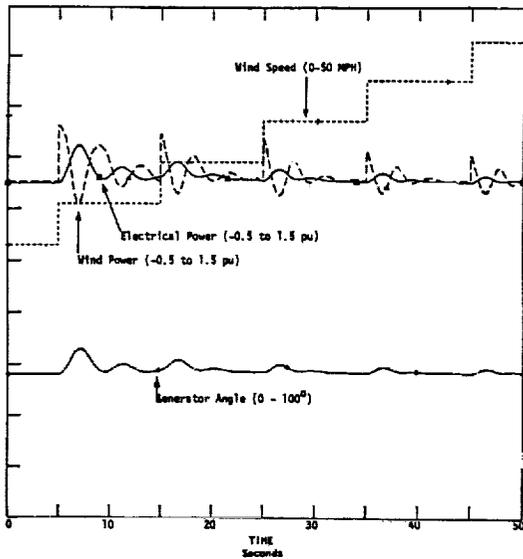


Figure 4.2 4 MPH Step Increases in Wind Speed

Figure 4.3 depicts the behavior of a MOD-2 WIG during and after a 0.1 sec. three-phase fault at the high side of the generator step-up transformer. The four traces in Figure 4.3B show airgap torque, low speed shaft torque, blade torque, and high speed shaft torque. The two frequencies dominating the response are the 60 Hz system frequency during the fault, and the frequency of the electrical system mode after the fault. Even though airgap torques reach 6 p.u., turbine torques are hardly affected by this transient.

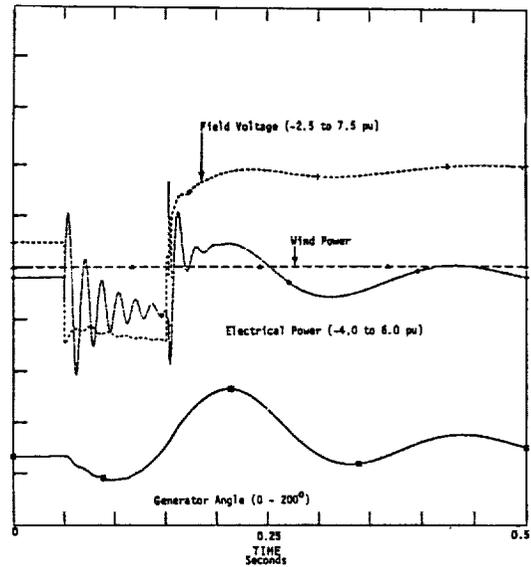


Figure 4.3A Three Phase Fault Near WIG for 0.1 Second

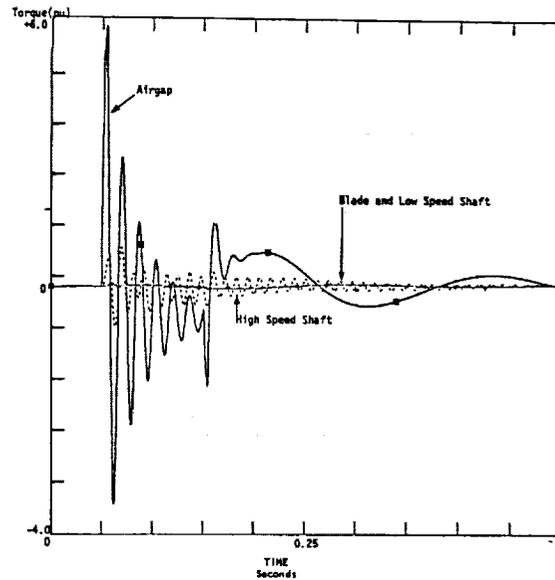


Figure 4.3B Torque Levels in MOD-2 Drive Train, Three Phase Fault Near WIG for 0.1 Second

Figure 4.4 shows the events occurring during and after a loss of electrical load for 0.5 seconds. The WIG is a MOD-2. The four traces in Figure 4.4A show generator speed, hub speed, blade speed, and gear speed. The generator rotor accelerates very quickly away from the synchronous reference frame, unwinding the turbine shaft and starting an oscillation with respect to the turbine. The generator rotor angle reaches 1000 degrees after approximately 0.5 sec. The turbine also begins to accelerate but at a much lower rate. As long as the turbine is still near synchronous speed, resynchronization is theoretically possible at any rotor angle. When the tie to the electrical system is restored at $t=0.55$ sec., the generator resynchronizes quickly at a rotor angle that differs from the original rotor angle by 1080 degrees (3×360). After the generator has been resynchronized, the turbine oscillates with respect to the generator at the frequency of the first torsional mode.

5. CONCLUSIONS

The dynamic and transient stability properties of wind turbine generators have been explored using eigenvalue and time response analysis. It has been shown that, unlike steam or hydro units, the dynamics of wind turbine generators are dominated by the torsional characteristics of the drive train. The most significant characteristic of such systems is the presence of an inherently poorly damped shaft mode having a frequency below 0.5 Hz.

Various schemes for introducing damping in the low frequency shaft mode are discussed. Inclusion of a hub speed damping signal in systems which have blade pitch control is shown to be particularly effective. The rationale for choosing electric power as the regulated variable is also considered and the advantages of choosing turbine speed instead of electric power are debated.

The unusual characteristics of the drive train are shown to have a decoupling effect on electrically and mechanically produced transients. Faults on the electrical side do not stimulate the low frequency shaft mode to any appreciable extent. Similarly, even large wind speed disturbances do not influence the electrical system mode.

Consistent with the above decoupling between the electrical and shaft modes, it is seen that electrically produced damping is not particularly effective in damping the first shaft mode. This implies that speed sensitive stabilizers operating on synchronous machine excitation, or induction generator damping will have limited effect on damping of the dominant shaft mode.

Further consequences of the unusual torsional system characteristics are the excellent transient stability properties and ability to synchronize a wind turbine through large phase and speed mismatches. Impact torque levels during fault and network switchings are lower than in typical steam units due to the inherent decoupling between generator and turbine.

From the viewpoint of network disturbances, both induction and synchronous machines exhibit a relatively high frequency oscillatory mode (typically 20 to 30 rads/sec.). This high frequency results from the lightness of the generator rotor and the softness of the torsional spring between generator and hub. Damping of the first torsional shaft mode and power control response do not vary appreciably with electrical system parameters.

No adverse interactions have been predicted for groups of wind turbines synchronized together. The only coupling is through the electrical system which is shown to have little influence on the power control loop or shaft mode damping. The main result of interconnection will be coupling between electrical modes. The intermachine electrical modes are not normally of concern as they are not stimulated by asymmetric wind disturbances (due to the soft shaft effect) and are not stimulated by electrical disturbances on the common transmission system.

The conclusions regarding the absence of interaction in the multi-machine case have been confirmed by carrying out detailed simulations of a three wind turbine system with each machine represented explicitly.

In addition to more detailed simulation to complement the results summarized in this paper the authors feel that further work in the following areas is warranted:

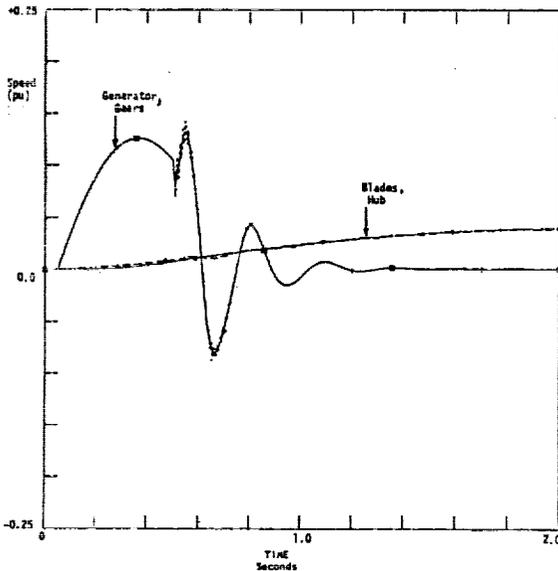


Figure 4.4A Speeds in MOD-2 Drive Train, Loss of Load for 0.5 Second

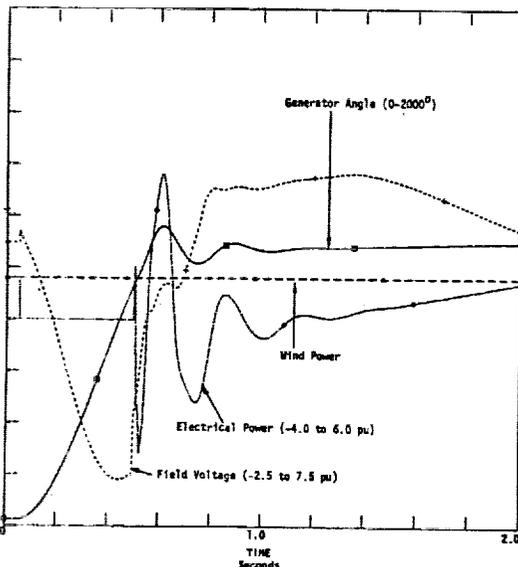


Figure 4.4B Loss of Load for 0.5 Second

Shaft Torque Levels

Figure 4.3B demonstrates another characteristic of the torsional system of wind turbine generators: low levels of shaft torque during disturbances. The mechanical limitation of WIGs during several electrical disturbances is not strength at shafts but rather the bracing of generator windings. The bracing required does not exceed conventional levels.

Synchronization

The unusual torsional dynamics of wind turbine generator drive trains can be used to advantage during synchronization. Turbine and generator are decoupled transiently by the apparent low shaft stiffness. This reduces the need for accurate matching of voltage, speed, and phase angle prior to synchronization. Speed errors of several percent and angle deviations of 30-40 degrees can be tolerated.

- o The use of turbine speed as the regulated variable for pitch control systems. This would make wind turbine control functionally equivalent to steam and hydro turbine control.
- o The limitation of using electrical power as the regulated variable in pitch control systems. The limitations will become apparent when WIGs are connected to noninfinite power systems.
- o Other methods of damping the first torsional mode. Damping by pitch control is effective but is inactive at low wind speeds. Electrical damping is not particularly effective.
- o Out of step synchronization WIGs are very tolerant to out-of-step synchronization. The usefulness of this characteristic for reclosing and synchronization should be evaluated.

6. REFERENCES

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- [3]. R. T. Alden, P. J. Nolan and J. P. Bayne, "Shaft Dynamics in Closely Coupled Identical Generators," IEEE Trans. on Power Apparatus and Systems, Vol. PAS 77, No. 3, pp. 721-728, May/June, 1977.

QUESTIONS AND ANSWERS

E.N. Hinrichsen

From: D.L. Hughes

Q: a) Did you examine the effect of controlling the tips with any other form of feedback (e.g., torque/acceleration)?

b) Is rotor flexibility important in determining dynamic response of system with tip control?

A: a) Yes. We examined the behavior of this system with primary turbine control based on power. We found that the sensitivity of pitch control to electrical disturbances was greatly reduced and the response to wind speed disturbances was essentially the same.

b) We have not looked at rotor flexibility. It is unlikely that rotor flexibility affects the two modes which principally determine electrical system behavior.

From: Anonymous

Q: What is the sacrifice in energy capture as a result of controlling the pitch angle at lower wind speeds?

A: No quantitative answer available.

From: F.A. Stoddard

Q: I assume the aerodynamic model in your wind turbine $\Delta P/\Delta\beta$ is linear. Do you have any feeling for the effects of 1) dynamic stall and 2) quasi-steady or unsteady aerodynamics?

A: The aerodynamic model is not linear. Figure 3.1 is a linearized version of the actual model. The actual model includes the full nonlinear representation of $c_p = f(\lambda, \beta)$. Unsteady aerodynamics are probably best treated as disturbances of the $\Delta P/\Delta\beta$ transfer function. Their principle effect would be stimulation of the first torsional mode.

From: W.C. Walton

Q: a) The frequencies of the important modes - what ratio to nP?

b) Does blade elasticity influence the modes?

A: a) At rated power (approximately):

	MOD-1 (34 RPM)	MOD-1 (23 RPM)	MOD-2 (17.6 RPM)
First torsional:	0.7	1.1	0.8
Second torsional:	8.3	12.4	16.5

Since the frequency of the second torsional (electrical) mode is a function of electrical stiffness, its frequency varies with electrical system reactance. The values given here are for a stiff electrical system.

b) It is unlikely that blade elasticity affects the two modes important for electrical stability and control. It will create higher modes which probably lie outside the range of interest at pitch control and electrical system dynamics.

consideration of the utility configuration control loop requires a stiffness greater than 460,000 ft-lb/radian, which is important only at torque levels near rated torque.

CONTROL LOOP GAIN

A review of Figures 1 and 2 shows that the magnitude of the control loop gain is determined by the following:

No Load:

$$\text{Gain} = (A_C) \left(\frac{\partial T_R}{\partial \theta} \right) \left(\frac{1}{C_R + C_{GL}} \right)$$

Utility With Load:

$$\text{Gain} = (A_C) \left(\frac{\partial T_R}{\partial \theta} \right) \left(\frac{1}{C_R + C_{GL} + C_{GC}} \right) (A_G)$$

Standalone With Load:

$$\text{Gain} = (A_C) \left(\frac{\partial T_R}{\partial \theta} \right) \left(\frac{1}{C_R + C_{GL} + C_L} \right)$$

where:

A_C = Controller gain factor

$\frac{\partial T_R}{\partial \theta}$ = change in rotor torque per unit change in pitch angle

C_R = slope of the rotor torque-speed curve, C_{GL} , C_{GC} , C_L , as defined on Figure 2

A_G = a constant that relates generator power to generator slip speed

Two of these factors, $\frac{\partial T_R}{\partial \theta}$ and C_R , are derived from the rotor characteristics and vary considerably over the range of expected operating conditions. The slope of the torque-speed curve, C_R , increases from 170 ft-lb-sec/radian at 10 mph to 6254 ft-lb-sec/radian at 60 mph. The torque derivative with pitch, $\frac{\partial T_R}{\partial \theta}$, is zero when the maximum available power is being delivered (i.e., regulation is not possible). However, if power is restricted to the lesser of 40 kW or 80% of the maximum available, the torque derivative increases from 90 ft-lb/deg. to 1980 ft-lb/deg. as the wind increases from 10 to 60 mph. The three gain functions, normalized to their values at 20 mph are shown on Figure 7. The functions with load are based on the lesser of 40 kW or 80% of the maximum power available.

The loop gain in the no load case changes by a factor of almost 5. However, this case is primarily concerned with startup which takes place when the wind speed increases above 10 mph or decreases below 60 mph. The loop gains at these two points only differ by a factor of 1.5. More importantly, the control loop stability analysis indicated that a fixed controller gain could be selected that would provide adequate speed regulation at 10 and

60 mph and satisfactory overshoot characteristics at 20 - 25 mph. Test data has verified this projection up to 30 mph. Test data for startups above 30 mph have not yet been collected.

When the standalone configuration is operated with full load, the changes in the torque derivative are almost fully compensated by changes in the total damping and the loop gain is essentially constant. As the load is decreased, the curve approaches the no load curve. In this case also, the control loop stability shows sufficient gain margin to achieve adequate speed regulation and satisfactory overshoot characteristics under all of the wind speed and load conditions.

The utility configuration differs in two respects. First, the damping term is dominated by C_{GC} , the very steep slope of the induction generator torque-speed curve. Therefore, the change in loop gain is almost equal to the change in the torque derivative, a factor of 20 for 10 to 60 mph. Second, because of the added phase lag of the drive shaft dynamics, the gain margin available is much less than that available in the other modes. The result is that the controller gain that provides adequate power regulation at 20 - 25 mph causes instability at 60 mph. Therefore, the controller gain in this mode is made a function of the mean wind speed such that the total loop gain remains essentially constant.

RESPONSE TO WIND SPEED CHANGES

The ability of a variable-pitch wind turbine to maintain a given power level in the presence of wind speed changes is limited by the capabilities of the pitch change mechanism. Therefore, knowledge of the wind variability that must be accommodated is needed to establish the required capabilities of the pitch change mechanism.

To meet this need, the description of wind variability must relate the magnitude of wind speed changes to the time interval over which they are observed and the frequency with which they can be expected at the planned location of the wind turbine. The magnitude and time interval, with respect to the dynamic characteristics of the wind turbine, determine the impact on the wind turbine. The frequency determines whether or not they need to be accommodated. For example, wind speed changes that cause disruptions in the delivered power less frequently than once per month or once per year need not be accommodated. However, the system must accommodate wind speed changes that could cause damage more frequently than once per lifetime of the machine.

Cliff and Fichtl (Reference 1) have developed a description of wind speed changes based on turbulence theory. It allows the calculation of the root-mean-square (RMS) value of the change in wind speed over a time interval as a function of the mean wind speed, nature of the terrain (surface roughness), height above the surface, and the scale of the affected device. The RMS value and the characteristics of a Normal distribution determine the probability of exceeding a particular magnitude of speed change in any one time interval. The probability and the duration of the observation time interval determine the